# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended June 30, 2008**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from to**

**Commission file number 1-10934**

# ENBRIDGE ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **39-1715850** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**1100 Louisiana**
**Suite 3300**
**Houston, TX 77002**
(Address of principal executive offices and zip code)

**(713) 821-2000**
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large Accelerated Filer ☒ | Accelerated Filer ☐ |
| Non-Accelerated Filer ☐ (Do not check if a smaller reporting company) | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The Registrant had 59,838,834 Class A common units outstanding as of July 29, 2008.

**ENBRIDGE ENERGY PARTNERS, L.P.**

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**PART I. FINANCIAL INFORMATION**



*In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "should," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007 and in Part II, Item 1A of our quarterly reports on Form 10-Q.*

## PART I—FINANCIAL INFORMATION

### Item 1. Financial Statements

## ENBRIDGE ENERGY PARTNERS, L.P.

## CONSOLIDATED STATEMENTS OF INCOME

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions, except per unit amounts) | | | |
| Operating revenue | $2,932.2 | $1,738.7 | $5,367.5 | $3,451.4 |
| Operating expenses | | | | |
| Cost of natural gas (Notes 9 and 10) | 2,614.3 | 1,475.6 | 4,713.1 | 2,959.9 |
| Operating and administrative | 121.8 | 105.1 | 238.5 | 202.8 |
| Power | 31.3 | 27.3 | 69.6 | 57.4 |
| Depreciation and amortization | 55.3 | 39.8 | 104.5 | 76.3 |
| | 2,822.7 | 1,647.8 | 5,125.7 | 3,296.4 |
| Operating income | 109.5 | 90.9 | 241.8 | 155.0 |
| Interest expense | 51.4 | 21.5 | 79.0 | 46.8 |
| Other income | 2.5 | 0.5 | 2.2 | 1.9 |
| Income before income tax expense | 60.6 | 69.9 | 165.0 | 110.1 |
| Income tax expense | 1.8 | 1.3 | 3.1 | 2.4 |
| Net income | $ 58.8 | $ 68.6 | $ 161.9 | $ 107.7 |
| Net income allocable to limited partner units (Note 2) | $ 48.4 | $ 59.3 | $ 140.2 | $ 90.7 |
| Net income per limited partner unit (basic and diluted) (Note 2) | $ 0.50 | $ 0.69 | $ 1.49 | $ 1.10 |
| Weighted average limited partner units outstanding | 96.3 | 86.5 | 94.4 | 82.2 |

The accompanying notes are an integral part of these consolidated financial statements.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| | (unaudited; in millions) | | | |
| Net income | $ 58.8 | $68.6 | $ 161.9 | $107.7 |
| Other comprehensive income (loss), net of tax benefit of $1.0, $0, $2.8 and $1.3 (Notes 9 and 10) | (164.2) | 5.3 | (190.5) | (35.0) |
| Comprehensive income (loss) | $(105.4) | $73.9 | $ (28.6) | $ 72.7 |

The accompanying notes are an integral part of these consolidated financial statements.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Six months ended June 30, | |
|---|---|---|
| | 2008 | 2007 |
| | (unaudited; in millions) | |
| Cash provided by operating activities | | |
| Net income | $ 161.9 | $ 107.7 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 104.5 | 76.3 |
| Derivative fair value losses (Notes 9 and 10) | 30.1 | 12.6 |
| Other | 10.9 | (1.5) |
| Changes in operating assets and liabilities, net of cash acquired: | | |
| Receivables, trade and other | (14.9) | 49.4 |
| Due from General Partner and affiliates | (6.3) | 5.0 |
| Accrued receivables | (265.3) | 43.5 |
| Inventory (Note 4) | (21.3) | (3.9) |
| Current and long term other assets (Notes 9 and 10) | (2.8) | (4.5) |
| Due to General Partner and affiliates | 18.9 | 19.7 |
| Accounts payable and other (Notes 3, 9 and 10) | 2.8 | (14.5) |
| Accrued purchases | 258.7 | (42.4) |
| Interest payable | 13.8 | 5.3 |
| Property and other taxes payable | 4.8 | 6.0 |
| Settlement of interest rate derivatives (Note 10) | (22.1) | — |
| Net cash provided by operating activities | 273.7 | 258.7 |
| Cash used in investing activities | | |
| Additions to property, plant and equipment | (672.1) | (891.5) |
| Changes in construction payables | (40.8) | 87.2 |
| Other | (5.4) | (1.1) |
| Net cash used in investing activities | (718.3) | (805.4) |
| Cash provided by financing activities | | |
| Net proceeds from unit issuances (Note 7) | 221.8 | 628.8 |
| Distributions to partners (Note 7) | (137.0) | (115.8) |
| Net repayments under Credit Facility (Note 6) | (150.0) | — |
| Net repayments of commercial paper (Note 6) | (168.6) | (46.5) |
| Net proceeds from Senior Note issuances (Note 6) | 790.2 | — |
| Net cash provided by financing activities | 556.4 | 466.5 |
| Net increase (decrease) in cash and cash equivalents | 111.8 | (80.2) |
| Cash and cash equivalents at beginning of year | 50.5 | 184.6 |
| Cash and cash equivalents at end of period | $ 162.3 | $ 104.4 |

The accompanying notes are an integral part of these consolidated financial statements.

## ENBRIDGE ENERGY PARTNERS, L.P.

## CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (unaudited; dollars in millions) | |
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents (Note 3) | $ 162.3 | $ 50.5 |
| Receivables, trade and other, net of allowance for doubtful accounts of $1.8 in 2008 and $1.9 in 2007 | 174.2 | 157.8 |
| Due from General Partner and affiliates | 33.5 | 27.2 |
| Accrued receivables | 864.1 | 598.8 |
| Inventory (Note 4) | 131.9 | 110.6 |
| Other current assets (Notes 9 and 10) | 10.1 | 14.8 |
| | 1,376.1 | 959.7 |
| Property, plant and equipment, net (Note 5) | 6,128.2 | 5,554.9 |
| Goodwill | 256.5 | 256.5 |
| Intangibles, net | 90.8 | 91.5 |
| Other assets, net (Notes 9 and 10) | 35.5 | 29.0 |
| | $7,887.1 | $6,891.6 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| Current liabilities | | |
| Due to General Partner and affiliates | $ 64.7 | $ 45.8 |
| Accounts payable and other (Notes 3, 8, 9 and 10) | 460.2 | 400.4 |
| Accrued purchases | 862.5 | 603.8 |
| Interest payable | 34.7 | 20.9 |
| Property and other taxes payable | 27.3 | 22.5 |
| Current maturities of long term debt | 231.0 | 31.0 |
| | 1,680.4 | 1,124.4 |
| Long term debt (Note 6) | 3,146.6 | 2,862.9 |
| Notes payable to affiliate | 130.0 | 130.0 |
| Other long-term liabilities (Notes 8, 9 and 10) | 302.4 | 202.8 |
| | 5,259.4 | 4,320.1 |
| Commitments and contingencies (Note 8) | | |
| Partners' capital (Note 7) | | |
| Class A common units (59,838,834 at June 30, 2008 and 55,238,834 at December 31, 2007) | 1,523.4 | 1,340.7 |
| Class B common units (3,912,750 at June 30, 2008 and December 31, 2007) | 77.1 | 72.9 |
| Class C units (18,767,526 at June 30, 2008 and 18,073,367 at December 31, 2007) | 900.7 | 874.1 |
| i-units (14,070,848 at June 30, 2008 and 13,564,086 at December 31, 2007) | 542.4 | 515.3 |
| General Partner | 69.0 | 62.9 |
| Accumulated other comprehensive loss (Notes 9 and 10) | (484.9) | (294.4) |
| | 2,627.7 | 2,571.5 |
| | $7,887.1 | $6,891.6 |

The accompanying notes are an integral part of these consolidated financial statements.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)**

## 1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of June 30, 2008 and December 31, 2007; the results of operations for the three and six month periods ended June 30, 2008 and 2007; and our cash flows for the six month periods ended June 30, 2008 and 2007. We derived the Consolidated Statement of Financial Position as of December 31, 2007, from the audited financial statements included in our 2007 Annual Report on Form 10-K. The results of operations for the three and six month periods ended June 30, 2008, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, timing and completion of our construction projects, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

***Comparative Amounts***

We have made reclassifications to the amounts reported in our prior year consolidated statement of financial position and our consolidated statements of cash flows to conform to our current year presentation. We reclassified $2.8 million of "Environmental liabilities" to "Other long-term liabilities" in our December 31, 2007 consolidated statement of financial position. We also reclassified $2.3 million for changes in the balance of "Current income tax payable" to "Property and other taxes payable" on our consolidated statements of cash flows.

## 2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after deducting our allocation to our general partner, Enbridge Energy Company, Inc. (the "General Partner"), by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per limited partner unit was determined as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions, except per unit amounts) | | | |
| Net income | $ 58.8 | $68.6 | $161.9 | $107.7 |
| Allocations to the General Partner: | | | | |
| Net income | (1.1) | (1.4) | (3.2) | (2.2) |
| Incentive distributions to the General Partner | (9.2) | (7.9) | (18.4) | (14.7) |
| Historical cost depreciation adjustments | (0.1) | — | (0.1) | (0.1) |
| | (10.4) | (9.3) | (21.7) | (17.0) |
| Net income allocable to limited partner units | $ 48.4 | $59.3 | $140.2 | $ 90.7 |
| Net income per limited partner unit (basic and diluted) | $ 0.50 | $0.69 | $ 1.49 | $ 1.10 |
| Weighted average limited partner units outstanding | 96.3 | 86.5 | 94.4 | 82.2 |

## 3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution, in the amounts of approximately $46.5 million at June 30, 2008 and $38.5 million at December 31, 2007, are included in "Accounts payable and other" on our consolidated statements of financial position.

## 4. INVENTORY

Inventory is comprised of the following:

| | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in millions) | |
| Materials and supplies | $ 3.9 | $ 3.9 |
| Liquids inventory | 28.1 | 6.7 |
| Natural gas and natural gas liquids inventory | 99.9 | 100.0 |
| | $131.9 | $110.6 |

## 5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

| | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in millions) | |
| Land | $ 14.3 | $ 14.3 |
| Rights-of-way | 476.8 | 345.8 |
| Pipelines | 3,972.2 | 2,703.2 |
| Pumping equipment, buildings and tanks | 1,045.7 | 854.7 |
| Compressors, meters, and other operating equipment | 590.0 | 536.1 |
| Vehicles, office furniture and equipment | 134.7 | 123.3 |
| Processing and treating plants | 297.9 | 200.4 |
| Construction in progress | 731.8 | 1,813.9 |
| Total property, plant and equipment | 7,263.4 | 6,591.7 |
| Accumulated depreciation | (1,135.2) | (1,036.8) |
| Property, plant and equipment, net | $ 6,128.2 | $ 5,554.9 |

## 6. DEBT

### *Credit Facility*

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date from April 4, 2012 to April 4, 2013.

At June 30, 2008, we had $250 million outstanding under our Credit Facility at a weighted average interest rate of 2.86% and letters of credit totaling $297.4 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At June 30, 2008 we could borrow $602.6 million under the terms of our Credit Facility, determined as follows:

| | June 30, 2008 |
|---|---|
| | (in millions) |
| Total credit available under Credit Facility | $1,250.0 |
| Less: Amounts outstanding under Credit Facility | (250.0) |
| Balance of letters of credit outstanding | (297.4) |
| Principal amount of commercial paper issuances | (100.0) |
| Total amount we could borrow at June 30, 2008 | $ 602.6 |

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the six months ended June 30, 2008, we net settled borrowings of approximately $410 million on a non-cash basis.

### *Commercial Paper Program*

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At June 30, 2008 and

December 31, 2007, respectively, we had $99.8 million and $268.5 million of commercial paper outstanding, net of unamortized discount of $0.2 million and $1.5 million, at weighted average interest rates of 3.09% and 5.36%. At June 30, 2008 we could issue an additional $500 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying consolidated statements of financial position.

***Senior Notes***

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 million in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.2 million after initial purchasers' discounts and payment of offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable on April 15th and October 15th of each year and we may redeem the Notes for cash in whole or in part at any time, at our option. Pursuant to a registration rights agreement we agreed to file, and have filed in July 2008, a registration statement with the Securities and Exchange Commission ("SEC") offering to exchange the Notes for registered notes with similar principal amounts and terms.

## 7. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the six months ended June 30, 2008:

| Distribution Declaration Date | Distribution Payment Date | Record Date | Distribution per Unit | Cash available for distribution | Amount of Distribution of i-units to i-unit Holders(1) | Amount of Distribution of Class C units to Class C unit Holders(2) | Retained from General Partner(3) | Distribution of Cash |
|---|---|---|---|---|---|---|---|---|
| April 28, 2008 | May 15, 2008 | May 7, 2008 | $0.950 | $102.2 | $13.1 | $17.5 | $0.6 | $71.0 |
| January 28, 2008 | February 14, 2008 | February 6, 2008 | $0.950 | $ 96.7 | $12.9 | $17.2 | $0.6 | $66.0 |

(1) During 2008, in lieu of cash distributions, the Partnership issued 506,762 i-units to Enbridge Management.

(2) During 2008, in lieu of cash distributions, the Partnership issued 694,159 Class C units to our Class C unitholders.

(3) The Partnership retains an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner in respect of its 2 percent general partner interest.

***Issuance of Class A Common Units***

On March 3, 2008, we issued and sold 4.6 million Class A common units, including 0.6 million units from the over-allotment option that was exercised by the underwriters, at a price to the public of $49.00 per unit, for proceeds of approximately $217.2 million, net of underwriters' discounts, commissions and issuance costs. In addition, our general partner contributed approximately $4.6 million to us to maintain its two percent general partner interest. We used the proceeds from this offering to partially reduce outstanding commercial paper we issued and amounts we previously borrowed under our Credit Facility to finance a portion of our capital expansion projects. We invested a portion of the proceeds for use in future periods to fund additional expenditures under our capital expansion projects.

## 8. COMMITMENTS AND CONTINGENCIES

***Environmental Liabilities***

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

As of June 30, 2008 and December 31, 2007, we have recorded $4.5 million and $3.4 million, respectively, in "Accounts payable and other" and $3.0 million and $2.8 million, respectively, in "Other long-term liabilities," primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

***Legal Proceedings***

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

## 9. FAIR VALUE MEASUREMENTS

We adopted the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. SFAS No. 157 provides guidance for determining fair value and requires increased disclosure regarding the inputs to valuation techniques used to measure fair value. SFAS No. 157 defines fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. In the case of our liabilities, our nonperformance risk is considered in the valuation, based upon the ratings assigned to our debt obligations by the nationally recognized statistical ratings organizations. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

SFAS No. 157 establishes a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.

- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those derivative instruments that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources. (i.e., supported by little or no market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 instruments primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value; however, the cost of obtaining the information is prohibitive.

Derivative contracts can be exchange-traded or over-the counter ("OTC"). We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of the fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to lacking binding broker quotes to corroborate pricing data as required by current interpretations of SFAS No. 157 Level 2 requirements. Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or the interpretation of Level 2 criteria is modified in practice to include non-binding market corroborated data.

The following table sets forth by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

| Recurring fair value measures | Fair Value at June 30, 2008 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| | (in millions) | | | |
| Assets: | | | | |
| Derivative instruments, net | $ — | $— | $ 10.1 | $ 10.1 |
| Liabilities: | | | | |
| Derivative instruments, net | (338.8) | — | (217.5) | (556.3) |
| Total | $(338.8) | $— | $(207.4) | $(546.2) |

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the six months ended June 30, 2008. As reflected in the table, the net unrealized loss on Level 3 financial assets and liabilities was $91.3 million for the six months ended June 30, 2008, which resulted from forward price increases in natural gas, natural gas liquids, or NGLs, and crude oil derivative instruments that we held at June 30, 2008.

| | Derivative Instruments, net |
|---|---|
| | (in millions) |
| Balance at January 1, 2008 | $(160.6) |
| Realized and unrealized net losses | (44.3) |
| Purchases and settlements | (2.5) |
| Transfer in (out) of Level 3 | — |
| Balance at June 30, 2008 | $(207.4) |
| Change in unrealized net losses relating to instruments still held at June 30, 2008 | $ (91.3) |

## 10. DERIVATIVE FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGL, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility of our cash flows. Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by a committee of senior management. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with forecasted natural gas and NGL sales and purchases through 2013 in accordance with our risk management policies.

### *Accounting Treatment*

We record all derivative instruments in our consolidated financial statements at fair value pursuant to the provisions of Statement of Financial Accounting Statement No. 133, *Accounting for Deriviative Instruments and Hedging Activities*, or SFAS No. 133, and the guidance set forth in SFAS No. 157 as discussed in Note 9 above. We adjust our consolidated financial statements each period for changes in the fair value of our derivative instruments, which we refer to as “marking to market” or “mark-to-market.” For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period.

Under the guidance of SFAS No. 133, if a derivative instrument does not qualify as a hedge, or is not designated as a hedge, the derivative instrument is adjusted to its fair value each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in “Cost of natural gas” for our commodity-based derivatives. Our cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative instrument occurs.

If a derivative instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in “Accumulated other comprehensive income” (“AOCI”), a component of Partners’ Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge’s change in fair value is recognized each period in earnings. Realized gains and losses on derivative instruments that are designated as hedges and qualify for hedge accounting are included in “Cost of natural gas” in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges, for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

***Non-Qualified Hedges***

Many of our derivative instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as “non-qualified.” Non-qualified derivative instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in “Cost of natural gas” in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated derivative instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation**—In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is generally different from the pricing index used for natural gas purchases, exposing us to basis price risk relative to changes in those two indices. By entering into a basis swap, we can effectively lock in the margin, or “spread,” representing the difference between the sales price and the purchase price, on the combined

natural gas purchase and natural gas sale, thereby removing locational price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative instruments (i.e., the basis swaps) associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative instruments are recorded in earnings.

2. **Storage**—In our Marketing segment, we use derivative instruments (i.e., natural gas swaps) to hedge the "margin," representing relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative instruments is to lock in the margin between storage injections and withdrawals in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we retain the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative instrument is settled in a period that is different from when the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars**—In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a New York Mercantile Exchange ("NYMEX") price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. The changes in fair value of these derivative instruments from the date of de-designation are recorded in earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes**—In our Natural Gas segment we use derivative instruments to hedge NGL volumes produced from our natural gas processing facilities. Many of our natural gas contracts provide us with the option of processing natural gas when it is economical, and allow us to cease processing when the "fractionation spread," representing the relative difference between the price received for the NGLs produced less the cost of natural gas used for processing, becomes uneconomic. We have entered into derivative instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing when it is probable the processing will occur. Because our processing forecasts fluctuate due to market conditions, these derivative instruments are deemed "non-qualifying" hedges. For this reason, our operating income will be subject to increased volatility due to fluctuations in both natural gas and NGL prices until the underlying transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting treatment between the derivative instrument and the underlying transaction (i.e., the derivative instruments are recorded at fair value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of "Cost of natural gas" for our commodity-based derivative instruments and "Interest expense" for our interest rate derivative instruments in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

| Derivative fair value gains (losses) | Three months ended June 30, 2008 | Three months ended June 30, 2007 | Six months ended June 30, 2008 | Six months ended June 30, 2007 |
|---|---|---|---|---|
| | (in millions) | | | |
| Natural Gas segment | | | | |
| Hedge ineffectiveness | $ 0.7 | $ 0.2 | $ (1.2) | $ 0.3 |
| Non-qualified hedges | (22.7) | (2.8) | 6.0 | (6.0) |
| Marketing | | | | |
| Non-qualified hedges | (22.0) | 6.3 | (34.9) | (6.9) |
| Commodity derivative fair value gains (losses) | (44.0) | 3.7 | (30.1) | (12.6) |
| Corporate | | | | |
| Non-qualified interest rate hedges | 0.2 | — | — | — |
| Derivative fair value gains (losses) | $(43.8) | $ 3.7 | $(30.1) | $(12.6) |

### *De-designation and Settlement of Derivatives*

We record the change in fair value of our cash flow hedges in AOCI until the derivative instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI at June 30, 2008 are unrecognized losses of approximately $1.8 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three months and six months ended June 30, 2008, we reclassified losses of $29.0 million and $60.3 million, respectively, from AOCI to "Cost of natural gas" on our consolidated statements of income for the fair value of derivative instruments that were settled.

In connection with our April 2008 issuance and sale of $800 million in principal amount of Notes, we paid $22.1 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the Notes maturing in 2038. The $22.1 million is being amortized from AOCI to"Interest expense" over the 30-year term of the Notes.

### *Derivative Positions*

Our derivative financial instruments are included at their fair values in our consolidated statements of financial position as follows:

| | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in millions) | |
| Other current assets | $ 4.0 | $ 6.5 |
| Other assets, net | 1.8 | 6.4 |
| Accounts payable and other | (260.6) | (165.5) |
| Other long-term liabilities | (291.4) | (192.9) |
| | $(546.2) | $(345.5) |

The increase in our obligation associated with derivative activities is primarily due to an increase in forward and daily natural gas, NGL and condensate prices from December 31, 2007 to June 30, 2008. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We present the fair value of our derivative contracts on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

The table below summarizes our counterparty credit quality and exposures, in millions of dollars.

| Counterparty Credit Quality* | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in millions) | |
| AAA | $ — | $ — |
| AA | (352.4) | (298.3) |
| A | (193.8) | (47.2) |
| Lower than A | — | — |
| Total | $(546.2) | $(345.5) |

* As determined by nationally recognized statistical ratings organizations.

## 11. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

| | For the three months ended June 30, 2008 | | | | |
|---|---|---|---|---|---|
| | Liquids | Natural Gas | Marketing | Corporate[1] | Total |
| | | | (in millions) | | |
| Total revenue | $189.2 | $2,280.7 | $1,474.2 | $ — | $3,944.1 |
| Less: Intersegment revenue | 0.2 | 944.3 | 67.4 | — | 1,011.9 |
| Operating revenue | 189.0 | 1,336.4 | 1,406.8 | — | 2,932.2 |
| Cost of natural gas | — | 1,192.6 | 1,421.7 | — | 2,614.3 |
| Operating and administrative | 41.3 | 77.1 | 2.3 | 1.1 | 121.8 |
| Power | 31.3 | — | — | — | 31.3 |
| Depreciation and amortization | 26.7 | 28.2 | 0.4 | — | 55.3 |
| Operating income | 89.7 | 38.5 | (17.6) | (1.1) | 109.5 |
| Interest expense | — | — | — | 51.4 | 51.4 |
| Other income | — | — | — | 2.5 | 2.5 |
| Income before income tax expense | 89.7 | 38.5 | (17.6) | (50.0) | 60.6 |
| Income tax expense | — | — | — | 1.8 | 1.8 |
| Net income | $ 89.7 | $ 38.5 | $ (17.6) | $(51.8) | $ 58.8 |
| Capital expenditures (excluding acquisitions) | $204.9 | $ 90.4 | $ — | $ 3.3 | $ 298.6 |

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

| | For the three months ended June 30, 2007 | | | | |
|---|---|---|---|---|---|
| | Liquids | Natural Gas | Marketing | Corporate[1] | Total |
| | | | (in millions) | | |
| Total revenue | $129.4 | $1,384.4 | $954.3 | $ — | $2,468.1 |
| Less: Intersegment revenue | — | 670.1 | 59.3 | — | 729.4 |
| Operating revenue | 129.4 | 714.3 | 895.0 | — | 1,738.7 |
| Cost of natural gas | — | 591.8 | 883.8 | — | 1,475.6 |
| Operating and administrative | 40.6 | 60.9 | 1.9 | 1.7 | 105.1 |
| Power | 27.3 | — | — | — | 27.3 |
| Depreciation and amortization | 16.7 | 22.4 | 0.7 | — | 39.8 |
| Operating income | 44.8 | 39.2 | 8.6 | (1.7) | 90.9 |
| Interest expense | — | — | — | 21.5 | 21.5 |
| Other income | — | — | — | 0.5 | 0.5 |
| Income before income tax expense | 44.8 | 39.2 | 8.6 | (22.7) | 69.9 |
| Income tax expense | — | — | — | 1.3 | 1.3 |
| Net income | $ 44.8 | $ 39.2 | $ 8.6 | $(24.0) | $ 68.6 |
| Capital expenditures (excluding acquisitions) | $270.2 | $ 219.2 | $ 0.3 | $ 2.5 | $ 492.2 |

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

| | As of and for the six months ended June 30, 2008 | | | | |
|---|---|---|---|---|---|
| | Liquids | Natural Gas | Marketing | Corporate[(1)] | Total |
| | | | (in millions) | | |
| Total revenue | $ 346.2 | $4,154.8 | $2,673.0 | $ — | $7,174.0 |
| Less: Intersegment revenue | 0.2 | 1,654.4 | 151.9 | — | 1,806.5 |
| Operating revenue | 346.0 | 2,500.4 | 2,521.1 | — | 5,367.5 |
| Cost of natural gas | — | 2,180.4 | 2,532.7 | — | 4,713.1 |
| Operating and administrative | 78.8 | 152.0 | 4.6 | 3.1 | 238.5 |
| Power | 69.6 | — | — | — | 69.6 |
| Depreciation and amortization | 46.3 | 57.3 | 0.9 | — | 104.5 |
| Operating income | 151.3 | 110.7 | (17.1) | (3.1) | 241.8 |
| Interest expense | — | — | — | 79.0 | 79.0 |
| Other income | — | — | — | 2.2 | 2.2 |
| Income before income tax expense | 151.3 | 110.7 | (17.1) | (79.9) | 165.0 |
| Income tax expense | — | — | — | 3.1 | 3.1 |
| Net income | $ 151.3 | $ 110.7 | $ (17.1) | $(83.0) | $ 161.9 |
| Total assets | $3,460.5 | $3,652.4 | $ 549.5 | $224.7 | $7,887.1 |
| Capital expenditures (excluding acquisitions) | $ 501.7 | $ 163.9 | $ — | $ 6.5 | $ 672.1 |

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

| | As of and for the six months ended June 30, 2007 | | | | |
|---|---|---|---|---|---|
| | Liquids | Natural Gas | Marketing | Corporate[(1)] | Total |
| | | | (in millions) | | |
| Total revenue | $ 262.2 | $2,708.7 | $1,843.7 | $ — | $4,814.6 |
| Less: Intersegment revenue | — | 1,238.9 | 124.3 | — | 1,363.2 |
| Operating revenue | 262.2 | 1,469.8 | 1,719.4 | — | 3,451.4 |
| Cost of natural gas | — | 1,255.0 | 1,704.9 | — | 2,959.9 |
| Operating and administrative | 74.3 | 122.2 | 3.5 | 2.8 | 202.8 |
| Power | 57.4 | — | — | — | 57.4 |
| Depreciation and amortization | 33.1 | 42.4 | 0.8 | — | 76.3 |
| Operating income | 97.4 | 50.2 | 10.2 | (2.8) | 155.0 |
| Interest expense | — | — | — | 46.8 | 46.8 |
| Other income | — | — | — | 1.9 | 1.9 |
| Income before income tax expense | 97.4 | 50.2 | 10.2 | (47.7) | 110.1 |
| Income tax expense | — | — | — | 2.4 | 2.4 |
| Net income | $ 97.4 | $ 50.2 | $ 10.2 | $(50.1) | $ 107.7 |
| Total assets | $2,279.0 | $3,074.0 | $ 353.1 | $170.4 | $5,876.5 |
| Capital expenditures (excluding acquisitions) | $ 493.4 | $ 385.9 | $ 1.5 | $ 10.7 | $ 891.5 |

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

## 12. SUBSEQUENT EVENT

***Distribution to Partners***

On July 28, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2008. The distribution will be paid to unitholders of record as of August 6, 2008, of our available cash of $108.0 million at June 30, 2008, or $0.990 per common unit. Of this distribution, $74.8 million will be paid in cash, $13.9 million will be distributed in i-units to our i-unitholder, $18.6 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

## 13. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

***Disclosures about Derivative Instruments and Hedging Activities***

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

***Calculation of Earnings Per Unit***

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read together with our consolidated financial statements and the accompanying notes included in "Item 1. Financial Statements" of this report.

Additionally, this quarterly report on Form 10-Q should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2007.

### RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for the three and six month periods ended June 30, 2008 and 2007:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions) | | | |
| **Operating Income** | | | | |
| Liquids | $ 89.7 | $44.8 | $151.3 | $ 97.4 |
| Natural Gas | 38.5 | 39.2 | 110.7 | 50.2 |
| Marketing | (17.6) | 8.6 | (17.1) | 10.2 |
| Corporate, operating and administrative | (1.1) | (1.7) | (3.1) | (2.8) |
| **Total Operating Income** | 109.5 | 90.9 | 241.8 | 155.0 |
| Interest expense | 51.4 | 21.5 | 79.0 | 46.8 |
| Other income | 2.5 | 0.5 | 2.2 | 1.9 |
| Income tax expense | 1.8 | 1.3 | 3.1 | 2.4 |
| **Net Income** | $ 58.8 | $68.6 | $161.9 | $107.7 |

Several types of arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide, or where we purchase natural gas or NGLs. We employ derivative financial instruments to reduce our exposure to natural gas and NGL price volatility. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

***Summary Analysis of Operating Results***

*Liquids*

Operating income from our Liquids segment increased by $44.9 million and $53.9 million to $89.7 million and $151.3 million for the three and six months ended June 30, 2008, respectively, from the $44.8 million and $97.4 million for the same periods in 2007. The increase in operating income of our Liquids segment is primarily due to the following:

- Higher delivery volumes on a majority of our Liquids systems;
- Tariff increases that went into effect during the second half of 2007 and the first half of 2008, which include increases associated with completion of the first stage of our Southern Access Expansion and the Phase V expansion of our North Dakota system; and
- Higher average crude oil prices resulted in additional revenue from the allowance oil we receive in connection with our transportation services.

*Natural Gas*

Operating income from our Natural Gas segment decreased to $38.5 million for the three months ended June 30, 2008 from the $39.2 million for the same period of 2007. Operating income for the six months ended June 30, 2008 increased by $60.5 million to $110.7 million, from $50.2 million for the comparable period in 2007.

For the three month period ended June 30, 2008, a $19.4 million increase in unrealized non-cash mark-to-market losses from our derivative activities had a negative affect on the operating income of our Natural Gas business in relation to the same period of 2007. The following additional factors also affected the operating income of our Natural Gas business:

- Improved margins for our gathering, processing and treating services resulting from higher prices for natural gas, NGLs and condensate we receive as payment for the services we provide, coupled with additional processing and treating capacity we added in the second half of 2007 and first half of 2008;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier, Granite Wash and Barnett Shale formations; and
- Variable operating and administrative costs increased in proportion to the volumes increases and expanded capacity of our natural gas systems.

For the six months ended June 30, 2008, in addition to the factors discussed above, we had $4.8 million of unrealized, non-cash mark-to-market gains, representing a $10.5 million improvement from the $5.7 million of losses we experienced in the same period of 2007. Additionally, operating income for the six months ended June 30, 2008 was not affected by unscheduled maintenance at our Zybach processing facility and measurement losses which negatively affected operating income during the same period of 2007.

*Marketing*

Operating income from our Marketing segment decreased by $26.2 million and $27.3 million to operating losses of $17.6 million and $17.1 million for the three and six months ended June 30, 2008, respectively, from operating income of $8.6 million and $10.2 million for the same periods in 2007. The operating results of our Marketing segment were negatively affected by unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. Partially offsetting these derivative losses is income derived from selling natural gas and NGLs into markets with more favorable pricing.

*Derivative Transactions and Hedging Activities*

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133, and the guidance set forth in Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS No. 157"). For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

The fair values of all our derivative instruments reflect our best estimate of the price we would receive for selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. SFAS No. 157 defines how we are to determine fair value, establishes criteria for measuring fair value, and requires additional disclosures for assets and liabilities that we report at fair value. We adopted the provisions of SFAS No. 157 prospectively beginning January 1, 2008, which did not affect our results of operations, financial condition or cash flows due to the nature of our derivative instruments and our existing valuation methods.

Our unrealized, non-cash mark-to-market losses of $43.8 million and $30.1 million for the three and six months ended June 30, 2008, are primarily the result of higher forward and daily prices of natural gas and NGLs relative to March 31, 2008 and December 31, 2007. The changes in fair value of our portfolio of commodity—based derivative instruments that do not qualify for hedge accounting are a result of the volatility in the underlying prices for natural gas, NGLs and crude oil. We also had $0.2 million of unrealized, non-cash mark-to-market gains in connection with interest rate derivatives that do not qualify for hedge accounting treatment under SFAS No. 133. During the three months ended June 30, 2007 we had unrealized, mark-to-market gains that were the result of a decline in the forward and daily market prices of natural and NGLs from March 31, 2007. However, during the six months ended June 30, 2007, increasing natural gas and NGL prices from December 31, 2006, produced non-cash mark-to-market net losses of $12.6 million and negatively affected our operating results for that period. Mark-to-market gains or losses create volatility in our operating results although the derivative instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative instruments against the underlying physical transactions. We intend to continue using derivative instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from minimizing the volatility in our cash flows. Our continued use of derivative instruments is likely to result in additional unrealized, non-cash gains or losses in the future.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of "Cost of natural gas" for our commodity-based derivative instruments and "Interest expense" for our interest rate derivative instruments in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **Derivative fair value gains (losses)** | **2008** | **2007** | **2008** | **2007** |
| | (in millions) | | | |
| Natural Gas segment | | | | |
| Hedge ineffectiveness | $ 0.7 | $ 0.2 | $ (1.2) | $ 0.3 |
| Non-qualified hedges | (22.7) | (2.8) | 6.0 | (6.0) |
| Marketing | | | | |
| Non-qualified hedges | (22.0) | 6.3 | (34.9) | (6.9) |
| Commodity derivative fair value gains (losses) | (44.0) | 3.7 | (30.1) | (12.6) |
| Corporate | | | | |
| Non-qualified interest rate hedges | 0.2 | — | — | — |
| Derivative fair value gains (losses) | $(43.8) | $ 3.7 | $(30.1) | $(12.6) |

## RESULTS OF OPERATIONS—BY SEGMENT

### *Liquids*

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions) | | | |
| **Operating Results** | | | | |
| Operating revenues | $189.0 | $129.4 | $346.0 | $262.2 |
| Operating and administrative | 41.3 | 40.6 | 78.8 | 74.3 |
| Power | 31.3 | 27.3 | 69.6 | 57.4 |
| Depreciation and amortization | 26.7 | 16.7 | 46.3 | 33.1 |
| Operating expenses | 99.3 | 84.6 | 194.7 | 164.8 |
| **Operating Income** | $ 89.7 | $ 44.8 | $151.3 | $ 97.4 |
| **Operating Statistics** | | | | |
| **Lakehead system:** | | | | |
| United States[(1)] | 1,235 | 1,138 | 1,246 | 1,192 |
| Province of Ontario[(1)] | 322 | 340 | 351 | 338 |
| **Total Lakehead system deliveries**[(1)] | 1,557 | 1,478 | 1,597 | 1,530 |
| **Barrel miles (billions)** | 103 | 97 | 212 | 200 |
| **Average haul (miles)** | 728 | 722 | 728 | 722 |
| **Mid-Continent system deliveries**[(1)] | 237 | 248 | 244 | 245 |
| **North Dakota system:** | | | | |
| Trunkline | 107 | 92 | 105 | 89 |
| Gathering | 6 | 6 | 5 | 6 |
| **Total North Dakota system deliveries**[(1)] | 113 | 98 | 110 | 95 |
| **Total Liquids Segment Delivery Volumes**[(1)] | 1,907 | 1,824 | 1,951 | 1,870 |

(1) Average barrels per day ("Bpd") in thousands.

***Three months ended June 30, 2008 compared with three months ended June 30, 2007***

Our Liquids segment accounted for $89.7 million of operating income during the three months ended June 30, 2008, an increase of $44.9 million from the $44.8 million generated during the same period in 2007. The favorable results are attributable to increased volumes transported on our Liquids systems coupled with tariff increases that went into effect during 2007 and 2008, while actively managing our costs. The majority of the increase in delivery volumes is attributable to our Lakehead system; however, our North Dakota system also realized increased delivery volumes.

Operating revenue for the three months ended June 30, 2008 increased by $59.6 million to $189.0 million from $129.4 million for the same period in 2007. The increase in operating revenue is due to the following:

- The toll charges that are associated with completion of the first stage of our Southern Access expansion project became effective April 1, 2008 and we began to realize revenues in connection with this increased surcharge as crude oil is delivered from our Lakehead system. Our Southern Access expansion project includes a 42-inch diameter pipeline from Superior to Delavan, Wisconsin along with pump station enhancements upstream and downstream of this segment. Completion of the first stage of this project added approximately 190,000 Bpd of capacity and was placed into service April 1, 2008;

- New tariffs also went into effect on our North Dakota system effective January 1, 2008, to implement two new surcharges associated with the Phase V expansion that was completed and placed into service in January 2008;
- We increased the average tariffs on all three of our Liquids systems in connection with the annual index rate increase that went into effect July 1, 2007;
- We experienced higher delivery volumes on a majority of our systems; and
- Higher crude oil prices have also generated additional revenue associated with the allowance oil we receive in connection with our transportation services.

We implemented new tariffs in 2008 on our Lakehead system effective April 1, 2008 to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include four projects: (1) the Southern Access mainline expansion, (2) two Superior terminal tank projects, (3) two Griffith terminal tank projects and (4) the Clearbrook Manifold project. This filing increased the average tariff for crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.34 per barrel, to an average of approximately $1.21 per barrel. We also implemented new tariffs on our North Dakota system effective January 1, 2008 that are applicable for five years and are applied to all transportation routes with a destination of Clearbrook, Minnesota. Additionally, we increased the average tariffs on all three of our Liquids systems in connection with the annual index rate ceiling adjustment that went into effect July 1, 2007. The increases in average tariffs on all three Liquids systems coupled with longer hauls and transportation of more heavy crude oil contributed approximately $43.3 million of additional operating revenue.

Average delivery volumes on our Lakehead system increased approximately 5.3 percent, to 1.557 million Bpd during the three months ended June 30, 2008 from 1.478 million Bpd during the same period in 2007, contributing an additional $5.4 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands.

We receive an allowance from our customers for the transportation of crude oil. We recognize revenue for the contractually agreed-upon allowance at the prevailing market price for crude oil. The average prices of crude oil during the three months ended June 30, 2008 are substantially higher than the average prices for the same period of 2007. For example, the average price of West Texas Intermediate crude oil has increased in excess of 90 percent for the three months ended June 30, 2008 as compared to the same period in 2007. As a result of the increase in crude oil prices, we experienced an approximate $7.0 million increase in allowance oil revenues.

Oil measurement adjustments occur as part of the normal operations associated with our Liquids systems. The three types of oil measurement adjustments that normally occur on our systems include:

- Physical gains and losses, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- Degradation, which results from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and
- Revaluation, which is a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Operating and administrative expenses for the Liquids segment increased $0.7 million for the three months ended June 30, 2008, compared with the same period in 2007. The increase is driven primarily by additional workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our growing systems, offset by decreases in oil measurement adjustments and costs incurred in connection with our pipeline integrity program.

Power costs increased $4.0 million in the three months ended June 30, 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs.

The increase in depreciation expense of $10.0 million is attributable to the additional assets we have placed in service during the last two quarters of 2007 and the first two quarters of 2008, including the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008 along with the assets placed into service on our North Dakota and Mid-Continent systems.

***Six months ended June 30, 2008 compared with six months ended June 30, 2007***

Our Liquids segment accounted for $151.3 million of operating income during the six months ended June 30, 2008, representing a $53.9 million increase over the $97.4 million for the same period in 2007. The components comprising our operating income changed during the six months ended June 30, 2008 compared with the six months ended June 30, 2007, primarily for the same reasons as noted above in the three-month analysis.

*Future Prospects Update for Liquids*

We and Enbridge Inc. ("Enbridge") are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States. The following discussion provides an update to the status of projects we and Enbridge are constructing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2007.

Partnership Projects

*Southern Access*

We continue to progress on the second and final stage of the expansion project which will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois. Construction of this stage of the project commenced on June 1, 2008. We expect to complete this phase of the expansion by the end of the first quarter of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

*Alberta Clipper*

The Alberta Clipper project involves construction of a new 36-inch diameter, 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior, generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior and, at the request of our customers, we have revised the scope to also include a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.2 billion. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing on schedule with the project, which is expected to be in service in mid-2010.

*North Dakota*

The United States Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated natural gas resources of the Upper Devonian—Lower Mississippi Bakken formation in the United States portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil. Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. As a result, we have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed surcharge is similar to the structure being used on the recently completed Phase V expansion project and is subject to approval from the Federal Energy Regulation Commission ("FERC"). Regulatory applications have been filed and are pending approval.

*Superior and Griffith Storage*

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We are building two tanks with operational capacity of approximately 205,000 barrels each that are scheduled to be completed during 2008.

Enbridge and Other Projects

*Spearhead Pipeline*

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that previously shipped crude oil from Cushing to Chicago, Illinois. Enbridge reversed the pipeline, renamed it Spearhead, and began delivering Canadian crude oil to the major oil hub at Cushing in March 2006. Since then, the pipeline has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 190,000 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. The Spearhead pipeline is complementary to our Lakehead system as Western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. The Spearhead pipeline expansion is expected to be in service in early 2009.

*Southern Access Extension*

In July 2006, Enbridge announced that it received support from shippers and the Canadian Association of Petroleum Producers ("CAPP") for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Enbridge filed a petition for declaratory order with the FERC in October 2007, which was denied on May 7, 2008. Enbridge is currently working with shippers to develop a new commercial structure for the pipeline.

*Southern Lights*

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago, Illinois to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own, referred to as Line 13, for a similar section of a new pipeline to be constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

In February 2008, the National Energy Board ("NEB") issued its approval and in May 2008 the Canadian Government also issued its Governor In Council approval for the Canadian portion of the Southern Lights project. Enbridge has filed the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of Line 13 discussed above, which the FERC approved in late December 2007. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Construction and right-of-way acquisition related to this project continues in tandem with the Southern Access project. This project is expected to be placed in service in 2010.

*Texas Access Pipeline*

In December 2007, an open season was announced to solicit binding 15-year shipper commitments for the proposed Texas Access Pipeline, which concluded on March 14, 2008. The open season did not obtain the required level of commitment, and as a result, Enbridge continues to work with potential shippers to review alternatives to provide access for Western Canadian crude oil to the United States Gulf Coast.

*Trailbreaker (formerly Eastern PADD II Access)*

We and Enbridge are jointly developing plans to provide access for western Canadian crude oil to refineries along the United States eastern seaboard and the United States gulf coast via the marine terminal at Portland, Maine. The Trailbreaker project involves the expansion and reversal of existing facilities to create a pipeline route to Portland that is ready for use in 2010. Commercial terms for the project are being negotiated which will be subject to regulatory approvals in both the United States and Canada. Preliminary estimates indicate the Partnership's portion of the project will approximate $0.3 billion (excluding capitalized interest).

*Natural Gas*

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in millions of British Thermal Units per day ("MMBtu/d") for the periods presented:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** |
| | (unaudited; in millions) | | | |
| **Operating Results** | | | | |
| Operating revenues | $ 1,336.4 | $ 714.3 | $ 2,500.4 | $ 1,469.8 |
| Cost of natural gas | 1,192.6 | 591.8 | 2,180.4 | 1,255.0 |
| Operating and administrative | 77.1 | 60.9 | 152.0 | 122.2 |
| Depreciation and amortization | 28.2 | 22.4 | 57.3 | 42.4 |
| Operating expenses | 1,297.9 | 675.1 | 2,389.7 | 1,419.6 |
| **Operating Income** | $ 38.5 | $ 39.2 | $ 110.7 | $ 50.2 |
| **Operating Statistics (MMBtu/d)** | | | | |
| East Texas | 1,454,000 | 1,190,000 | 1,425,000 | 1,162,000 |
| Anadarko | 647,000 | 588,000 | 631,000 | 585,000 |
| North Texas | 392,000 | 352,000 | 380,000 | 336,000 |
| UTOS | 178,000 | 191,000 | 187,000 | 158,000 |
| MidLa | 91,000 | 131,000 | 108,000 | 120,000 |
| AlaTenn | 33,000 | 33,000 | 48,000 | 46,000 |
| Bamagas | 36,000 | 114,000 | 69,000 | 115,000 |
| Other major intrastates | 214,000 | 251,000 | 221,000 | 259,000 |
| Total[(1)] | 3,045,000 | 2,850,000 | 3,069,000 | 2,781,000 |

(1) We have excluded from the table above average daily volumes of 26,000 MMBtu/d and 32,000 MMBtu/d for the three and six month periods ended June 30, 2007, respectively, associated with the KPC system which we sold in November 2007.

***Three months ended June 30, 2008 compared with three months ended June 30, 2007***

Our Natural Gas segment contributed $38.5 million of operating income for the three months ended June 30, 2008, a decrease of $0.7 million from the $39.2 million contributed in the corresponding period of 2007. The following primary factors affected the operating income of our Natural Gas business for the three months ended June 30, 2008 as compared with the same period of 2007:

- $22.0 million of unrealized, non-cash mark-to-market losses from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $2.6 million for the same period of 2007;
- In-kind payments we receive for the services we provide in the form of natural gas, NGL and condensate have generated improved margins, representing revenues less cost of natural gas, as a result of rising prices in the commodities markets;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations; and
- Additional processing and treating capacity we added during the second half of 2007 and first half of 2008, coupled with the improved operating performance of our Zybach processing plant.

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on 20 to 30 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our margins increase when the prices of these commodities are rising and decrease when the prices are declining. For the three months ended June 30, 2008, we realized approximately $18 million of additional margin compared with the same period of 2007 primarily due to the higher prices we received from the sale of the unhedged natural gas, NGLs and condensate that we received in-kind as compensation for our services.

We enter into derivative financial instruments to hedge 70 to 80 percent of our near-term exposure to commodity prices associated with the in-kind compensation we receive for our services. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the processed natural gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate during that time. Many of these derivative financial instruments do not qualify for hedge accounting which results in the derivative instrument being marked-to-market in our operating results. This accounting treatment produces unrealized non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

The operating income of our Natural Gas segment for the three months ended June 30, 2008 was negatively affected by unrealized non-cash, mark-to-market net losses of $22.0 million, representing an increase of $19.4 million from the $2.6 million of losses we recorded for the same period of 2007. We expect the net mark-to-market losses to be offset when the related physical transactions are settled. The following table depicts the affect that unrealized non-cash mark-to-market gains and losses had on the operating results of our Natural Gas business for the three and six months ended June 30, 2008 and 2007:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **Derivative fair value gains (losses)** | **2008** | **2007** | **2008** | **2007** |
| | (in millions) | | | |
| Natural Gas segment | | | | |
| Hedge ineffectiveness | $ 0.7 | $ 0.2 | $(1.2) | $ 0.3 |
| Non-qualified hedges | (22.7) | (2.8) | 6.0 | (6.0) |
| Derivative fair value gains (losses) | $(22.0) | $(2.6) | $ 4.8 | $(5.7) |

We adopted the provisions of Financial Accounting Standards Board Statement No. 157, *Fair Value Measurements* (SFAS No. 157) effective January 1, 2008, which did not affect the operating results of our Natural Gas business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under "Derivative Activities" and the "Quantitative and Qualitative Disclosures about Market Risk" we include in Item 3 of this report for more information about our derivative activities.

The increase in our average daily volumes is directly attributable to the significant investments that we have made to expand the capacity and service capability of our systems. We completed the following projects during 2008 and the second half of 2007 which have contributed to the increase in average daily volumes and operating results of our major natural gas systems:

- In May 2008 our expansion of the Aker treating plant on our East Texas system was completed and placed into service adding 125 million cubic feet per day, or MMcf/d, of treating capacity.

- The $635 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, is substantially complete and includes:
  - ✓A new 36-inch natural gas pipeline from Bethel, Texas to Southeast Texas near Beaumont, Texas; and
  - ✓The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed in service in March 2007.

  We expect to finish an additional pipeline connection and two compression stations during the fourth quarter of 2008. The total added capacity related to this project will then total approximately 700 MMcf/d. Throughput for the second quarter of 2008 exceeded 350 MMcf/d and is expected to approximate 500 MMcf/d by the end of 2008.
- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction and expansion of the Weatherford processing facility within our North Texas system was completed late in 2007 and added approximately 75 MMcf/d of processing capacity.
- Our Hidetown processing facility on our Anadarko system with an approximate capacity of 120 MMcf/d was completed and placed into service in April 2007.

With the expansions we completed in 2007 and 2008 we are now able to provide additional gathering, processing, treating and transportation services for our customers which has contributed to volume growth during the second quarter of 2008. Volume and revenue growth is also the result of additional wellhead supply contracts and continued robust drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend and Barnett Shale areas. We expect the volumes on our major natural gas systems to continue increasing throughout the year as a result of our investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve.

Our processing margins also continue to benefit from a favorable pricing environment. NGL prices continue to remain high relative to natural gas prices providing a favorable environment for the production of NGLs from our processing assets. We also added approximately 120 MMcf/d of processing capacity on our Anadarko system in April 2007 and 75 MMcf/d on our North Texas system in the second half of 2007. The added processing capacity provided us with the ability to generate additional processing margin from the natural gas we processed for our customers during the second quarter of 2008. Our Zybach processing plant has also continued to operate at expected levels during the second quarter of 2008, which compares favorably with the second quarter of 2007 when we experienced operational issues that reduced processing margins by approximately $3 million.

A variable element of our Natural Gas segment's operating income is derived from the processing of natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems. Operating income derived from keep-whole processing arrangements for the three months ended June 30, 2008 was approximately $18 million, representing an increase of $1 million from the approximate $17 million of operating income derived from keep-whole processing for the same period in 2007. The relatively small change is a result of the improvement on our Anadarko system due to the addition of our Hidetown processing facility and the correction of the operational issues we experienced with our Zybach processing plant, both of which occurred in April 2007. We continue to experience a trend of replacing or renegotiating some of our existing keep-whole contracts with percent of liquids, or POL, type contracts and other similar arrangements. This trend may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing natural gas under keep-whole arrangements.

Operating and administrative costs of our Natural Gas segment were $16.2 million greater for the three months ended June 30, 2008 than the three months ended June 30, 2007, primarily as a result of increased workforce-related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly due to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our natural gas systems. We expect workforce related costs in addition to materials, supplies and other cost to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher in the second quarter of 2008 as compared the second quarter of 2007, as a result of the capital projects completed and placed in-service during the first half of 2008 and the second half of 2007. We expect deprecation expense will be higher in 2008 as a result of the projects we completed and placed in service throughout 2007 and the first half of 2008.

***Six months ended June 30, 2008 compared with six months ended June 30, 2007***

Our Natural Gas segment accounted for $110.7 million of operating income during the six months ended June 30, 2008, representing a $60.5 million increase over the $50.2 million for the same period in 2007. The components comprising our operating income changed favorably during the six months ended June 30, 2008 compared with the six months ended June 30, 2007, primarily for the same reasons noted above in our three-month analysis except for those items described below.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather, temperatures and variances in measurement that are inherent in metering technologies. During the first six months of 2007, we identified operating conditions on our gathering systems which contributed to an increase in measurement losses. We have since installed separator equipment to identify and reduce free-water in the natural gas streams, one of the underlying causes for the increase in measurement losses during 2007. As a result of the steps we took in 2007 to address the increase in measurement losses, the measurement losses we have experienced during the six months ended June 30, 2008 are in-line with our expectations.

Our Zybach processing plant has continued to operate at expected levels during the first half of 2008, which compares favorably with the same period of 2007 when we had unscheduled maintenance that reduced processing margins by approximately $11 million.

Operating income for the six months ended June 30, 2008 was positively affected by the unrealized non-cash, mark-to-market net gains of $4.8 million from our derivative activities, which is approximately

$10.5 million more than the $5.7 million of losses we recorded for the same period of 2007. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled.

*Future Prospects Update for Natural Gas*

We continue to assess various expansion opportunities to pursue our strategy for growth. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. Although we have successfully completed a majority of the significant expansion projects within our Natural Gas business, we are continually evaluating strategic opportunities to further expand the service capabilities of our existing systems. We may, and have, pursued opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During the second quarter of 2008, increased production from active drilling in the areas where our gathering systems are located has contributed to our volume growth. We expect the growth trend in these areas to continue in the future as evidenced by external production forecast and the strong rig counts and permitting in the areas served by our systems.

***Marketing***

The following table sets forth the operating results of our Marketing segment assets for the periods presented:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions) | | | |
| **Operating Results** | | | | |
| Operating revenues | $1,406.8 | $895.0 | $2,521.1 | $1,719.4 |
| Cost of natural gas | 1,421.7 | 883.8 | 2,532.7 | 1,704.9 |
| Operating and administrative | 2.3 | 1.9 | 4.6 | 3.5 |
| Depreciation and amortization | 0.4 | 0.7 | 0.9 | 0.8 |
| Operating expenses | 1,424.4 | 886.4 | 2,538.2 | 1,709.2 |
| **Operating Income (Loss)** | $ (17.6) | $ 8.6 | $ (17.1) | $ 10.2 |

A majority of the operating income of our Marketing segment is derived from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers who need natural gas. As a result of our natural gas system expansions and other initiatives, our Marketing business now has access to several additional downstream natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

We adopted the provisions of SFAS No. 157 effective January 1, 2008, which did not affect the operating results of our Marketing business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under “Derivative Activities” and the “Quantitative and Qualitative Disclosures about Market Risk” we include in Item 3 of this report for more information about our derivative activities.

***Three months ended June 30, 2008 compared with three months ended June 30, 2007***

The operating income of our Marketing segment declined to a loss of $17.6 million for the second quarter of 2008 from income of $8.6 million for the corresponding period in 2007. Included in operating income for the second quarter of 2008 are approximately $22.0 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with the $6.3 million of unrealized mark-to-market gains for the same period of 2007. The unrealized, mark-to-market losses for the three months ended June 30, 2008 result from increases in the forward and daily market prices of natural gas from March 31, 2008. We expect these net mark-to-market losses to be offset when the related physical transactions are settled. Partially offsetting the losses associated with the derivative activities of our Marketing business is income derived from selling natural gas and NGLs into markets with more favorable pricing.

The operating and administrative expenses of our Marketing business were slightly more in the quarter ended June 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

***Six months ended June 30, 2008 compared with six months ended June 30, 2007***

Similar to the three month analysis, operating income of our Marketing segment declined to a loss of $17.1 million for the six month period ended June 30, 2008 from income of $10.2 million for the corresponding period in 2007. Included in operating income for the first six months of 2008 are approximately $34.9 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, which are $28.0 million greater than the $6.9 million of unrealized mark-to-market losses for the comparable period of 2007. The unrealized, mark-to-market losses for the six months ended June 30, 2008 result from increases in the forward and daily market prices of natural gas from December 31, 2007. Partially offsetting the losses associated with the derivative activities of our Marketing business is income derived from selling natural gas and NGLs into markets with more favorable pricing. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

The operating and administrative expenses of our Marketing business are slightly more in the six months ended June 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

***Corporate***

Interest expense was $51.4 million and $79.0 million for the three months and six months ended June 30, 2008, compared with $21.5 million and $46.8 million for the corresponding periods in 2007. The increases are primarily the result of higher weighted average debt balance associated with the following debt issuances:

- $200 million of our Zero Coupon Senior Notes in August 2007,
- $400 million of our Junior Subordinated Notes in September 2007,
- $400 million of our 6.5% Senior Notes in April 2008, and
- $400 million of our 7.5% Senior Notes in April 2008.

Our weighted average interest rate is 6.2% for the three months and 6.1% for the six months ended June 30, 2008 as compared with our weighted average interest rates of 6.0% and 5.9% for the same periods in 2007.

Further contributing to the increase in interest expense is the $4.5 million decrease in interest capitalized to our construction projects in the three months ended June 30, 2008 from the same period in 2007. Conversely, the increase in interest expense in the first six months of 2008 was offset by an additional $6.1 million of capitalized interest when compared to the same period in 2007. For the three months and six months ended June 30, 2008 and 2007, our interest cost is comprised of the following:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 |
| | (unaudited; in millions) | | | |
| Interest expense | $51.4 | $21.5 | $ 79.0 | $46.8 |
| Interest capitalized | 5.9 | 10.4 | 25.0 | 18.9 |
| Interest cost incurred | $57.3 | $31.9 | $104.0 | $65.7 |

## LIQUIDITY AND CAPITAL RESOURCES

### *General*

We believe that our ability to generate cash flow, in addition to our access to capital, is sufficient to meet the demands of our current and future operating and investment needs. Our primary cash requirements consist of normal operating expenses, capital expenditures for our expansion projects, maintenance capital expenditures, debt service payments, distributions to our partners, acquisitions of new assets and businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures debt service payments and quarterly distributions to our partners, are expected to be funded by our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under our commercial paper program, our Credit Facility, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Although the internal growth projects we have planned require significant expenditures of capital over the next several years, since the beginning of 2007, we have raised in excess of $2.2 billion through the issuance of a balanced combination of debt and equity securities to fund these projects. We expect to use the same measured approach to fund the remaining expenditures from additional issuances of partnership capital and long-term debt. Our planned internal growth projects continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them.

### *Capital Resources*

### Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. In March 2008, we obtained approximately $221.8 million of cash from the public issuance and sale of 4.6 million of our Class A common units at a price to the public of $49.00 per unit, which consisted of $217.2 million of net proceeds, after payment of underwriters' discounts, commissions and offering expenses and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest. Additionally, in early April 2008, we completed the private issuance and sale of our

$400 million Notes due 2018 and our $400 million Notes due 2038 for net proceeds of approximately $790.2 million, after payment of initial purchasers' discounts and offering expenses. The Notes due 2018 bear interest at the rate of 6.50% and the Notes due 2038 bear interest at the rate of 7.50%. We used a portion of the proceeds from these offerings to repay outstanding issuances of commercial paper and borrowings under our Credit Facility, which we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs.

**Available Credit**

A significant source of our liquidity is provided by the commercial paper market and our Credit Facility. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally more competitive than the rates available under our Credit Facility.

United States credit markets in the second quarter of 2008 continue to remain volatile despite actions taken by United States and foreign regulators. Investors have continued to seek high-quality fixed income securities, favoring United States government securities over corporate issues. Although the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations are considered "investment grade," we may at times experience difficulty accessing the commercial paper and long-term credit markets due to current economic conditions. Despite the continuing weakness in the United States credit markets, we have sufficient available liquidity to manage our capital requirements into 2009.

*Credit Facility*

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date of the Credit Facility from April 4, 2012 to April 4, 2013.

The amounts we can borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At June 30, 2008, we had $250 million outstanding under our Credit Facility at a weighted average interest rate of 2.86% and letters of credit totaling $297.4 million. At June 30, 2008, we could borrow $602.6 million under the terms of our Credit Facility, determined as follows:

| | June 30, 2008 |
|---|---|
| | (in millions) |
| Total credit available under Credit Facility | $1,250.0 |
| Less: Amounts outstanding under Credit Facility | (250.0) |
| Balance of letters of credit outstanding | (297.4) |
| Principal amount of commercial paper issuances | (100.0) |
| Total amount we could borrow at June 30, 2008 | $ 602.6 |

*Commercial Paper Program*

At June 30, 2008, we had $100 million in principal amount of commercial paper outstanding, with unamortized discount of $0.2 million, at a weighted average interest rate of 3.09%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $168.6 million during the six months ended June 30, 2008, which include gross issuances of $1,025.8 million and gross repayments of $1,194.4 million. At June 30, 2008, we could issue an additional

$500 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

*EUS Credit Agreement*

In addition to our Credit Facility and commercial paper program, we have access to an unsecured three year revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. (the "EUS Credit Agreement"). The EUS Credit Agreement provides us with access to an additional $500 million of financing on substantially the same terms as our Credit Facility and matures in December 2010. The amounts available to us under the EUS Credit Agreement remain undrawn at June 30, 2008 and available for our use.

***Cash Requirements for Future Growth***

**Capital Spending**

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. In 2008, we expect to spend approximately $1.7 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. As of June 30, 2008, we have approximately $562.6 million in outstanding purchase commitments for materials and services associated with our capital projects for the construction of assets that we expect to settle during the remainder of 2008. However, we will incur additional commitments as our capital projects continue to progress.

*Forecasted Expenditures*

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2008. Although we anticipate making the indicated expenditures, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date to revise the scope of a project. We made capital expenditures of $672.1 million, including $32.1 million for core maintenance activities, during the six months ended June 30, 2008.

For the full year of 2008, we anticipate our capital expenditures to approximate the following in billions:

| | |
|---|---|
| System enhancements | $0.6 |
| Core maintenance activities | 0.1 |
| Southern Access expansion | 0.8 |
| Alberta Clipper | 0.2 |
| | $1.7 |

*Major Construction Projects*

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through June 30, 2008, the incremental capacity that will become available upon completion of the project and the periods during which we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

| | Capital Expenditures | | Estimated Incremental Capacity | | | |
|---|---|---|---|---|---|---|
| | Estimated Total Cost | Actual Expenditures through June 30, 2008 | Storage[1] | Oil[2] | Natural Gas[3] | Expected Completion |
| | (in billions) | | | | | |
| Southern Access expansion (Lakehead) | $2.1 | $1.5 | — | 400 | — | 2009 |
| Clarity (East Texas) | 0.6 | 0.6 | — | — | 700 | 2008 |
| Alberta Clipper | 1.2 | — | — | 450 | — | Mid-2010 |
| North Dakota phase VI expansion | 0.2 | — | — | 50 | — | Early 2010 |
| Griffith and Superior storage tanks | 0.1 | — | 1,220 | — | — | 2008 |
| Total | $4.2 | $2.1 | 1,220 | 900 | 700 | |

(1) Thousands of barrels (KBbl).

(2) Thousands of barrels per day (Kbpd).

(3) Millions of cubic feet per day (MMcf/d).

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper and borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

***Derivative Activities***

We use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative instruments at June 30, 2008:

| | Notional | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | | |
| Swaps | | | | | | | | |
| Natural gas[1] | 371,502,040 | $ (25.2) | $ (57.9) | $ (56.3) | $(45.5) | $ (8.3) | $(0.4) | $(193.6) |
| NGL[2] | 8,963,909 | (106.0) | (110.7) | (30.6) | (9.3) | (1.3) | — | (257.9) |
| Crude[2] | 1,483,146 | (21.7) | (24.5) | (18.2) | (13.8) | (11.3) | (0.7) | (90.2) |
| Options-calls | | | | | | | | — |
| Natural gas[1] | 1,279,000 | (1.7) | (2.9) | (2.4) | (2.1) | — | — | (9.1) |
| Options-puts | | | | | | | | — |
| Natural gas[1] | 1,462,000 | 0.1 | — | — | — | — | — | 0.1 |
| NGL[2] | 967,461 | 0.1 | 0.1 | 1.2 | 1.0 | 1.8 | — | 4.2 |
| Totals | | $(154.4) | $(195.9) | $(106.3) | $(69.7) | $(19.1) | $(1.1) | $(546.5) |

(1) Notional amounts for natural gas are recorded in MMBtu.

(2) Notional amounts for NGL and Crude are recorded in Bbl.

***Operating Activities***

Net cash provided by operating activities for the six months ended June 30, 2008 was $273.7 million, an increase of $15.0 million from the $258.7 million generated during the same period in 2007. The increase in operating cash flow is directly attributable to the improved operating performance of our Liquids and Natural Gas systems. Although net cash provided by operating activities increased, cash flows associated with changes in our working capital accounts for the six months ended June 30, 2008 were lower than the same period of 2007 due to higher commodity prices and the general timing differences in the collection on and payment of our current and related party accounts.

***Investing Activities***

We used $87.1 million less in our investing activities during the six months ended June 30, 2008 in relation to the same period in 2007. The decrease is attributable to the $91.4 million reduction of monies spent in the first six months of 2008 on our construction projects as compared to amounts spent during the same period of 2007. The decrease in the monies spent on our construction projects is primarily attributable to completion of our Clarity project and the first stage of our Southern Access expansion project.

***Financing Activities***

Net cash provided by financing activities during the six months ended June 30, 2008 was $556.4 million, compared with $466.5 million for the corresponding period in 2007. The increase in cash provided by financing activities is attributable to the following:

- $221.8 million we raised in March 2008 from the issuance of 4.6 million class A common units, which consisted of $217.2 million of net proceeds after underwriters' discounts, commissions and offering expenses, and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest.
- In early April 2008, we completed the private issuance and sale of our $400 million Notes due 2018 and our $400 million Notes due 2038 for net proceeds of approximately $790.2 million, after payment of initial purchasers' discounts and offering expenses.

The increase in cash raised from both our unit and debt issuances is partially offset by the following:

- $272.1 million increase in net repayments of our Credit Facility and commercial paper.
- $21.2 million more distributions to our partners for the first half of 2008 compared to the first half of 2007 due to a greater number of units outstanding, a higher distribution level and higher incentive distribution payments to our general partner.

For the six months ended June 30, 2008 we had gross borrowings of $1,715.0 million under our Credit Facility and gross repayments of $1,865.0 million, including $410.0 million of non-cash borrowings and repayments. Under our commercial paper program we had gross issuances of $1,025.8 million and gross repayments $1,194.4 million during the first half of 2008.

## OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

## SUBSEQUENT EVENTS

### *Distribution to Partners*

On July 28, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on August 14, 2008. The distribution will be paid to unitholders of record as of August 6, 2008, of our available cash of $108.0 million at June 30, 2008, or $0.990 per common unit. Of this distribution, $74.8 million will be paid in cash, $13.9 million will be distributed in i-units to our i-unitholder, $18.6 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

## REGULATORY MATTERS

### *FERC Transportation Tariffs-Liquids*

Effective July 1, 2008, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges. Effective July 2008, we increased the base tariff rates on our Lakehead system by an average of 8.2 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.26 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2008. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 5.2 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Effective April 1, 2008, we filed our annual tariff with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include four projects including the first stage of the Southern Access mainline expansion, two Superior and Griffith terminal tank projects and the Clearbrook Manifold project. This filing increased the average tariff for crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.34 per barrel, to an average of approximately $1.21 per barrel. We began to realize revenues in relation to this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff.

## OTHER MATTERS

We plan to amend our limited partnership agreement to modify the mechanism by which the capital accounts of all our partners are maintained when our general partner's incentive distribution rights are considered in determining the fair market value of the Partnership's assets in the event of a follow-on offering of our common units. We do not expect the amendment to materially change the amount of net taxable income or loss allocated to our unitholders or the economic rights of our unitholders as compared with the allocations or economic rights of our general partner.

## RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

***Disclosures about Derivative Instruments and Hedging Activities***

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

***Calculation of Earnings Per Unit***

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2007, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provides information about our derivative instruments at June 30, 2008 and December 31, 2007, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

| | At June 30, 2008 | | | | | | At December 31, 2007 | |
|---|---|---|---|---|---|---|---|---|
| | | | Wtd. Average Price[2] | | Fair Value[3] | | Fair Value[3] | |
| | Commodity | Notional[1] | Receive | Pay | Asset | Liability | Asset | Liability |
| ***Contract maturing in 2008*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive variable/pay fixed | Natural Gas | 14,746,544 | $ 12.54 | $ 7.76 | $70.1 | $ — | $ 7.6 | $(14.5) |
| | NGL | 60,000 | 127.50 | 87.44 | 2.4 | — | — | — |
| Receive fixed/pay variable | Natural Gas | 13,021,803 | 6.83 | 13.19 | — | (82.3) | 10.3 | (39.8) |
| | NGL | 2,904,072 | 42.37 | 80.03 | — | (108.4) | — | (98.9) |
| | Crude Oil | 275,648 | 61.68 | 140.96 | — | (21.7) | — | (17.7) |
| Receive variable/pay variable | Natural Gas | 110,035,465 | 12.71 | 12.83 | 13.2 | (26.2) | 7.0 | (3.5) |
| *Options* | | | | | | | | |
| Calls (written) | Natural Gas | 184,000 | 4.31 | 13.52 | — | (1.7) | — | (1.3) |
| Puts (purchased) | Natural Gas | 367,000 | 13.04 | 8.90 | 0.1 | — | — | — |
| | NGL | 218,129 | 81.49 | 46.99 | 0.1 | — | 0.1 | — |
| ***Contract maturing in 2009*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive variable/pay fixed | Natural Gas | 15,410,840 | $ 11.63 | $ 7.98 | $54.6 | $ — | $ 5.5 | $ (1.6) |
| | NGL | 176,870 | 84.03 | 63.69 | 3.5 | — | — | — |
| Receive fixed/pay variable | Natural Gas | 17,836,236 | 6.30 | 12.36 | — | (104.9) | 1.2 | (41.8) |
| | NGL | 3,735,045 | 46.19 | 77.80 | — | (114.2) | — | (43.6) |
| | Crude Oil | 354,625 | 69.29 | 140.74 | — | (24.5) | — | (7.2) |
| Receive variable/pay variable | Natural Gas | 102,218,673 | 12.43 | 12.50 | 3.8 | (11.4) | 2.9 | (1.8) |
| *Options* | | | | | | | | |
| Calls (written) | Natural Gas | 365,000 | 4.31 | 12.46 | — | (2.9) | — | (1.5) |
| Puts (purchased) | Natural Gas | 365,000 | 12.46 | 3.40 | — | — | — | — |
| | NGL | 365,000 | 80.24 | 42.09 | 0.1 | — | 0.6 | — |
| ***Contract maturing in 2010*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive variable/pay fixed | Natural Gas | 2,884,475 | $ 10.80 | $ 6.79 | $10.8 | $ — | $ 4.4 | $ — |
| | NGL | 45,625 | 66.88 | 57.63 | 0.4 | — | — | — |
| Receive fixed/pay variable | Natural Gas | 10,048,870 | 4.40 | 11.13 | — | (63.1) | — | (38.0) |
| | NGL | 1,331,155 | 44.08 | 69.14 | — | (31.0) | — | (13.8) |
| | Crude Oil | 332,150 | 79.29 | 138.29 | — | (18.2) | — | (4.4) |
| Receive variable/pay variable | Natural Gas | 61,625,000 | 11.15 | 11.22 | 0.3 | (4.3) | 1.5 | (0.7) |
| *Options* | | | | | | | | |
| Calls (written) | Natural Gas | 365,000 | 4.31 | 11.23 | — | (2.4) | — | (1.4) |
| Puts (purchased) | Natural Gas | 365,000 | 11.23 | 3.40 | — | — | — | — |
| | NGL | 172,280 | 70.85 | 59.23 | 1.2 | — | — | — |
| ***Contract maturing in 2011*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive variable/pay fixed | Natural Gas | 848,505 | $ 10.73 | $ 4.19 | $ 4.9 | $ — | $ 3.2 | $ — |
| Receive fixed/pay variable | Natural Gas | 7,955,920 | 3.63 | 10.77 | — | (50.6) | — | (34.1) |
| | NGL | 399,310 | 41.71 | 67.85 | — | (9.3) | — | (4.3) |
| | Crude Oil | 228,125 | 68.36 | 136.66 | — | (13.8) | — | (3.4) |
| Receive variable/pay variable | Natural Gas | 11,385,000 | 11.03 | 11.01 | 0.6 | (0.4) | 0.1 | — |
| *Options* | | | | | | | | |
| Calls (written) | Natural Gas | 365,000 | 4.31 | 10.78 | — | (2.1) | — | (1.4) |
| Puts (purchased) | Natural Gas | 365,000 | 10.78 | 3.40 | — | — | — | — |
| | NGL | 83,220 | 67.09 | 63.34 | 1.0 | — | — | — |

| | | | At June 30, 2008 | | | | At December 31, 2007 | |
|---|---|---|---|---|---|---|---|---|
| | | | Wtd. Average Price[2] | | Fair Value[3] | | Fair Value[3] | |
| | Commodity | Notional[1] | Receive | Pay | Asset | Liability | Asset | Liability |
| ***Contract maturing in 2012*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive variable/pay fixed . . . . . | Natural Gas | 209,709 | $ 11.31 | $ 4.10 | $ 1.3 | $ — | $ 0.9 | $ — |
| | NGL | 36,600 | 64.84 | 55.58 | 0.3 | — | — | — |
| Receive fixed/pay variable . . . . . | Natural Gas | 1,456,000 | 3.57 | 11.43 | — | (9.9) | — | (6.8) |
| | NGL | 275,232 | 61.00 | 67.72 | — | (1.6) | — | — |
| | Crude Oil | 219,600 | 74.85 | 136.06 | — | (11.3) | — | (1.9) |
| Receive variable/pay variable . . . | Natural Gas | 1,089,000 | 10.54 | 10.25 | 0.3 | — | — | — |
| *Options* | | | | | | | | |
| Puts (purchased) . . . . . . . . . . . | NGL | 128,832 | 70.24 | 66.80 | 1.8 | — | — | — |
| ***Contract maturing after 2012*** | | | | | | | | |
| *Swaps* | | | | | | | | |
| Receive fixed/pay variable . . . . . | Natural Gas | 730,000 | $ 9.83 | $ 10.43 | $ — | $ (0.4) | $ — | $ — |
| | Crude Oil | 73,000 | 124.05 | 136.07 | — | (0.7) | — | — |

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at June 30, 2008 and December 31, 2007, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

The table below summarizes our counterparty credit quality and exposures, in millions of dollars.

| Counterparty Credit Quality* | June 30, 2008 | December 31, 2007 |
|---|---|---|
| | (in millions) | |
| AAA . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | $ — | $ — |
| AA . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | (352.4) | (298.3) |
| A . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | (193.8) | (47.2) |
| Lower than A . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | — | — |
| Total . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . | $(546.2) | $(345.5) |

* As determined by nationally recognized statistical ratings organizations.

## Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2008. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. We have not made any changes that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three months ended June 30, 2008.

## PART II—OTHER INFORMATION

### Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 8, which is incorporated herein by reference.

### Item 1A. Risk Factors

There have been no material changes to our risk factors as previously disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

### Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

## SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**ENBRIDGE ENERGY PARTNERS, L.P.**
**(Registrant)**

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: July 29, 2008

By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
*Managing Director*
*(Principal Executive Officer)*

Date: July 29, 2008

By: /s/ MARK A. MAKI

Mark A. Maki
*Vice President—Finance*
*(Principal Financial Officer)*

## Index of Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

| | |
|---|---|
| 3.1 | Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425). |
| 3.2 | Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001). |
| 3.3 | Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006). |
| 3.4 | Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated January 3, 2008). |
| 4.1 | Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001). |
| 4.2 | Registration Rights Agreement dated as of April 3, 2008, by and among Enbridge Energy Partners, L.P., Banc of America Securities LLC, Deutsche Bank Securities Inc. and HSBC Securities (USA) Inc. (with respect to the 6.50% Notes due 2018) (incorporated by reference to exhibit 4.4 of our Current Report on Form 8-K dated April 7, 2008). |
| 4.3 | Registration Rights Agreement dated as of April 3, 2008, by and among Enbridge Energy Partners, L.P., Banc of America Securities LLC, Deutsche Bank Securities Inc. and HSBC Securities (USA) Inc. (with respect to the 7.50% Notes due 2038) (incorporated by reference to exhibit 4.5 of our Current Report on Form 8-K dated April 7, 2008). |
| 10.1 | Seventh Supplemental Indenture dated as of April 3, 2008 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee. (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K dated April 7, 2008). |
| 10.2 | Eighth Supplemental Indenture dated as of April 3, 2008 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee. (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K dated April 7, 2008). |
| 31.1* | Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1* | Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 32.2* | Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |